THE IMPACT OF RETAIL RATE STRUCTURES ON THE ECONOMICS OF CUSTOMER-SITED PV: A STUDY OF COMMERCIAL INSTALLATIONS IN CALIFORNIA

Dr. Ryan Wiser
Lawrence Berkeley National Laboratory
1 Cyclotron Road 90R4000
Berkeley, CA 94720
RHWiser@lbl.gov

Andrew Mills
Lawrence Berkeley National Laboratory
1 Cyclotron Road 90R4000
Berkeley, CA 94720
ADMills@lbl.gov

Galen Barbose
Lawrence Berkeley National Laboratory
1 Cyclotron Road 90R4000
Berkeley, CA 94720
GLBarbose@lbl.gov

Dr. William Golove
Chevron Energy Solutions
345 California Street, 18th Floor
San Francisco, CA 94104
whgolove@chevron.com

ABSTRACT

We analyze the impact of retail rate design on the economics of grid-connected commercial photovoltaic (PV) systems in California. The analysis is based on 15-minute interval building load and PV production data for 24 commercial PV installations in California, spanning a diverse set of building load shapes and geographic locations. We derive the annual bill savings per kWh generated for each PV system, under each of 21 distinct retail rates currently offered by the five largest utilities in California. We identify and explain variation in the value of bill savings attributable to differences in the structure of demand and energy charges across rates, as well as variation attributable to other factors, such as the size of the PV system relative to building load, the specific shape of the PV production profile, and the customer load profile. We also identify the optimal rate for each customer, among those rates offered as alternatives to one another, and show how the decision is driven in large measure by the size of the PV system relative to building load. The findings reported here may be of value to regulators and utilities responsible for designing retail rates, as well as to customers and PV retailers who have a need to estimate the prospective bill savings of PV systems.

1. INTRODUCTION

The solar power market is growing at a quickening pace, fuelled by an array of national and local initiatives and policies aimed at improving the value proposition of customer-sited photovoltaic (PV) systems. Though these policies take many forms, they commonly include up-front capital cost rebates or ongoing production incentives, supplemented by net metering requirements to ensure that customer-sited PV systems offset the full retail rate of the customer-hosts.

Somewhat less recognized is the role of retail rate design, beyond net metering, on the customer-economics of grid-connected PV systems. Over the life of a PV system, a substantial portion of the economic value received by the customer comes from utility bill savings. Thus, given the wide variation in retail rate design, particularly for commercial customers, one could reasonably expect that the specific structure of the customer's retail rate would be a significant factor in the overall financial value of PV for the customer.

This paper, which summarizes results from a recent study by Lawrence Berkeley National Laboratory (1), examines differences in the value of utility bill savings from customer-sited PV across 21 distinct rate schedules currently offered to commercial and industrial (C&I) customers in California. For each rate, we evaluate the annual bill savings using data from 24 actual PV installations at commercial facilities in the state.

We separately identify bill savings associated with reductions in energy and demand charges, and characterize the effect of differences in: rate structure, overall rate level, customer load profile, PV production profile, and the size of the PV system relative to customer load. In examining the role of rate design, we focus specifically on differences in:

- The type of demand charge(s) assessed;
- The type of energy charges assessed;
- The spread between peak and off-peak period prices (for time-of-use rates);
- The definition of the summer on-peak period; and
- The size of demand and energy charges relative to one another.

2. DATA AND METHODOLOGY

2.1 Commercial Customer Electricity Rates

We analyze the full set of standard C&I rates currently offered to customers with peak demands greater than 100 kW, by the five largest electric utilities in California: PG&E, SCE, SDG&E, LADWP, and SMUD.

These rates can be classified according the structure of their energy (volumetric) and demand charges (see Table 1). In terms of energy charges, the rate schedules each have either a flat energy rate, which has no variation over time, seasonal rates, which vary only between summer and winter months, or time-of-use (TOU) rates, which vary by time of day and, in some cases, also by season.

Each rate schedule may have multiple demand charges or none at all. Individual demand charges vary in terms of two separate parameters: the measure of maximum demand used and the variation in the $/kW demand charge rate over the course of the year. Among the rate schedules in our analysis, four basic types of demand charges are represented.

- *Annual, Fixed* demand charges are assessed on the customer's maximum demand over the past 12-month period, irrespective of when that peak occurs, and the demand charge rate is fixed at a single level throughout the year.
- *Monthly, Fixed* demand charges are assessed on the customer's maximum demand during each monthly billing period, irrespective of when the peak occurs within that month, and the $/kW demand charge rate is fixed at a single level throughout the year.
- *Monthly, Seasonal* demand charges are also assessed on the customer's maximum demand during each monthly billing period, but the $/kW demand charge rate varies seasonally, with a higher rate during summer months.
- *Time-of-Day (TOD), Seasonal* demand charges are assessed on the customer's maximum demand during one or more specific TOD periods in each monthly billing period, with different demand charge rates for different TOD periods. Among the rates in our analysis, the demand charge rates also vary by season.

TABLE 1: LIST OF RATES INCLUDED IN ANALYSIS

Utility	Rate Name	Energy Charge Type	Demand Charge Type(s)
LADWP	A-2, A	Flat	Annual, Fixed & Monthly, Seasonal
	A-2, B / A-3, C	TOU	Annual, Fixed & TOD, Seasonal
	A-2, D	TOU	Annual, Fixed
PG&E	A-1	Seasonal	-
	A-6	TOU	-
	A-10	Seasonal	Monthly, Seasonal
	A-10 TOU	TOU	Monthly, Seasonal
	E-19	TOU	Monthly, Fixed & TOD, Seasonal
	E-20	TOU	Monthly, Fixed & TOD, Seasonal
SCE	GS-2, Non-TOU	Seasonal	Monthly, Fixed & Monthly, Seasonal
	GS-2, TOU (Option A)	TOU	Monthly, Fixed
	GS-2, TOU (Option B)	TOU	Monthly, Fixed & Monthly, Seasonal
	TOU-GS-3 (Option A)	TOU	Monthly, Fixed
	TOU-GS-3 (Option B)	TOU	Monthly, Fixed & TOD, Seasonal
	TOU-8	TOU	Monthly, Fixed & TOD, Seasonal
SDG&E	AL-TOU	TOU	Monthly, Fixed & TOD, Seasonal
	A-6 TOU	TOU	Monthly, Fixed & TOD, Seasonal
SMUD	GS-Demand	Seasonal	Annual, Fixed
	GS-TOU3	TOU	Annual, Fixed & TOD, Seasonal
	GS-TOU2	TOU	Annual, Fixed & TOD, Seasonal
	GS-TOU1	TOU	-

2.2 Load and PV Production Data

We calculate the bill savings on each rate schedule using contemporaneous building load data and PV production data from 24 actual PV installations in California. Each dataset consists of 15-minute interval data and covers a period of at least one year. The 24 PV installations are from various geographical locations throughout the state (Northern and Southern, coastal and inland), and the customer loads represent a diverse range of load shapes. The datasets were reviewed and cleaned in order to eliminate erroneous data.

2.3 Analysis Methodology

For each combination of rate schedule and PV/load dataset, we calculate the value of the utility bill savings *per kWh generated*, according the equation below:

$$Value\ of\ \ PV = \frac{Total\ \ Bill\ \ without\ \ PV - Total\ \ Bill\ \ with\ \ PV}{Annual\ \ PV\ \ Energy\ \ Production} \quad (\$/kWh)$$

In calculating the value of the bill savings, we assume that PV systems are net metered according to the particular net metering rules of each utility, and that customers remain on the same rate before and after PV installation. Given that, in reality, customers often have a choice of rate options, we also separately analyze the optimal rate for each customer.

We calculate bill savings based on both the actual PV production data and adjusted PV production data that is scaled up or down so that the annual PV energy production is equal to specific percentages of the gross annual building energy consumption. We refer to these percentage values as *PV penetration levels*. Results in this paper are reported primarily for PV penetration levels of 2% and 75%.

3. VALUE OF PV WITH NO RATE SWITCHING

3.1 Key Trends

Figures 1 and 2 summarize the value of savings on demand and energy charges for each rate, at 2% and 75% PV penetration levels, respectively. These figures, and all others in Section 3, present the *median* values within a set of distributions, and the error bands represent the $10^{th}/90^{th}$ percentile values.

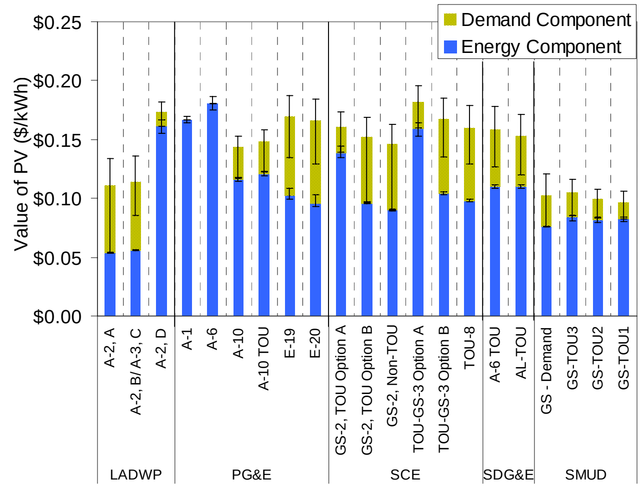

Fig. 1: Demand and Energy Savings at 2% PV Penetration

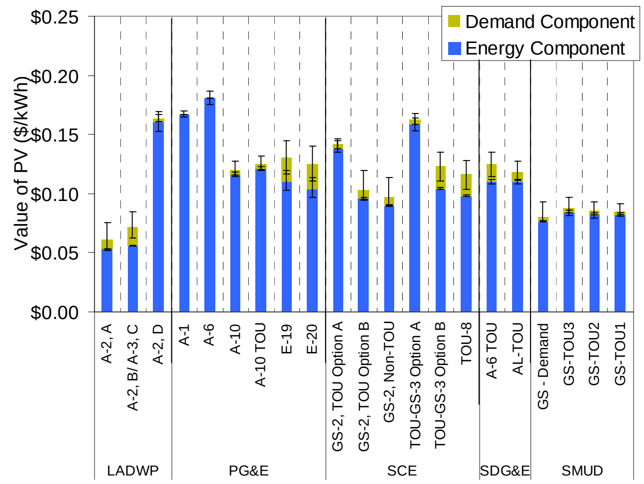

Fig. 2: Demand and Energy Savings at 75% PV Penetration

These figures support a number of basic observations, which we explain in subsequent sections of this paper:

- **The value of PV varies widely across rates.** This central finding is quite apparent. At a 2% penetration, the median value of PV varies by a factor of two across the 21 rates, from \$0.095/kWh to \$0.181/kWh. At a 75% penetration, the variation is even greater, ranging from \$0.061/kWh to \$0.178/kWh. The value of savings on demand and energy charges, individually, also clearly varies substantially across rates. These observed variations across rates reflect differences in both rate *design* and overall rate *level* (i.e., some rate schedules simply have larger charges, separate from the issue of how those charges are structured).
- **The value of demand charge savings can be substantial at low PV penetration levels, but declines dramatically with increasing PV penetration.** At a

2% PV penetration level, the median value of demand charge savings is as high as $0.05-$0.07/kWh for 8 of the 21 rates examined, in several cases comprising more than 50% of the total bill savings. However, at a 75% penetration level, the median value of demand charge savings declines precipitously, amounting to, at most, $0.01-$0.02 per kWh generated.

- **The value of demand charge savings is strongly affected by customer-specific conditions**. The percentile bands for demand charge savings span a wide range for most rates, indicating that the value of savings on demand charge depends critically on the specific shape of the customer load profile and/or PV production profile. As we show later, the customer load profile is the more important of the two factors.
- **The value of energy charge savings is relatively insensitive to PV penetration level and customer-specific conditions**. These conclusions are indicated by the fact that the value of energy charge savings does not vary significantly between Figures 1 and 2 and by the narrow percentile bands for the energy charge savings on most rates.

As noted above, variation in the value of PV across rates results from differences in both rate *level* and rate *structure*. In order to isolate the impact of differences in rate structure, in the remainder of the paper, we report bill savings on a *normalized* basis, where the values have been adjusted to account for differences across rates in rate level. Thus, variation in normalized values solely reflects differences in rate structure. Further explanation of the normalization method is provided in the full report (1).

3.2 <u>Impact of Demand Charge Structure</u>

To understand how the value of demand charge savings depends on the type of demand charge, it is useful to consider how customer-sited PV systems affect customer demand, itself. Figures 3-5 show the demand reduction at various PV penetration levels, based on the three primary measures of customer demand upon which demand charges are assessed: maximum *annual* demand, maximum *monthly* demand, and maximum monthly demand in the *summer peak TOD* period. Reductions in customer demand are expressed on a relative basis in terms of the system's *effective capacity*, equal to the demand reduction as a percentage of the PV system's maximum power output over the course of the year. The percentile bands show the variation across the 24 load/PV datasets.

In all three figures, effective capacity declines quite dramatically with increasing PV penetration levels, explaining the corresponding decline in demand charge savings noted previously. The physical basis underlying this trend is that, at higher levels of PV penetration, the customer's maximum demand shifts to times when PV production is minimal or non-existent.

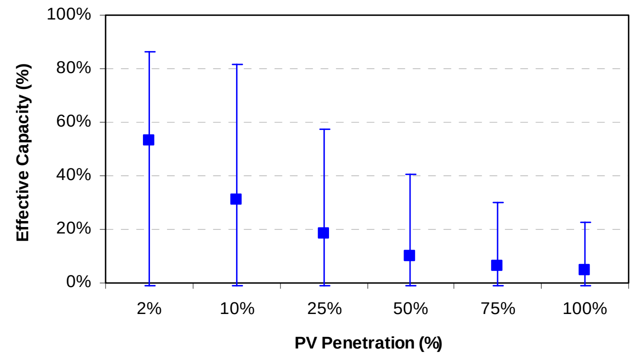

Fig. 3: Effective Capacity Based on Reduction in Maximum Annual Demand

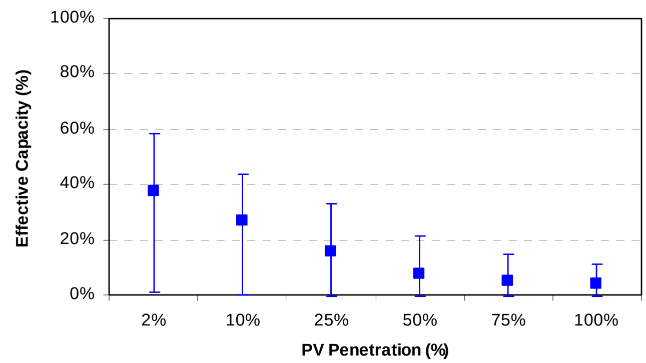

Fig. 4: Effective Capacity Based on Reduction in Maximum Monthly Demand (Averaged over 12 Months)

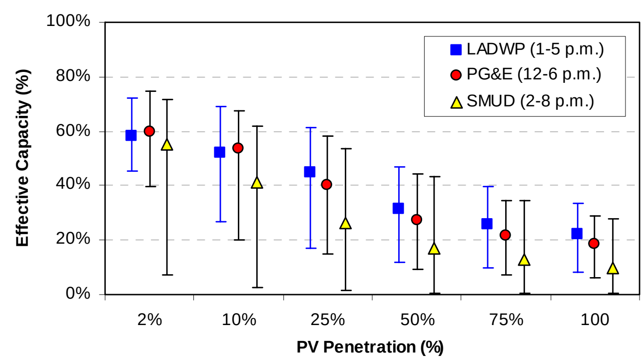

Fig. 5: Effective Capacity Based on Reduction in Maximum Summer Peak Period Demand (Averaged over Summer Months)

Notwithstanding the general similarities, several important differences between the figures can also be discerned, illustrating how demand charge savings depend, in part, on how maximum demand is defined. First, we can see that the effective capacity varies more widely across PV/load datasets, and is potentially greater, when demand charges are based on maximum annual demand rather than on maximum monthly demand. The physical basis for this trend is that customers whose annual peak occurs during summer months, when PV power output is highest, are credited for the corresponding higher level of demand reduction year-round, if demand charges are based on annual peak demand. Using similar reasoning, the demand reduction value of PV would tend to be greater when based on *monthly* peak demand, for customer with a dominant *winter* peak demand (a less common scenario in regions, such as California, where commercial customers' peak demand is driven largely by cooling loads).

In comparing across the three figures, we also observe that demand reductions are generally greatest for demand charges that are based on summer peak period demand. However, it is also quite clear that the value of those demand reductions can be quite sensitive to the particular definition of the summer peak period. In particular, demand reductions are greatest and least variable across customers (particularly at low PV penetration levels) the earlier that the peak period ends. The further the period extends into evening hours, the more likely it becomes that a customer's peak demand will occur in hours when its PV system is producing little or no energy, especially at high PV penetration levels. Thus, at PV penetration levels of 25% or more, the median effective capacity is essentially twice as large under LADWP's summer peak period definition, which ends at 5 p.m., than under SMUD's summer peak period, which ends at 8 p.m.

3.3 Impact of PV Production Profile on Demand Charge Savings

The wide range in demand charge savings for each individual rate, at a given PV penetration level, is the result of differences in the load/PV data among the 24 customers.

To isolate the effect of differences in PV production profiles, separate from the effect of differences in customer load profiles, we first selected five customers representative of different types of load shapes: one customer with a flat load profile, one with an inverted load profile, and three customers whose loads profiles have an afternoon peak. We then combined the load data for each of these five customers with the PV production data from each of the 24 sites (i.e., mixing-and-matching PV and load data across sites). We evaluated the demand charge savings for these paired datasets under two PG&E rates: A-10, which has a single demand charge assessed on monthly peak demand; and E-20, which also has a demand charge assessed on monthly peak demand, as well as substantial TOD-based demand charges.

Fig. 6 presents the results from this analysis. The percentile bands for each representative customer load solely reflect differences in the shape of the 24 PV production profiles that were paired with the load data. Given the narrow range of the percentile bands across all five customers, at both 2% and 75% PV penetration, we can conclude that the specific shape of the PV production profile (at least among these 24 systems) clearly has a minimal effect on the value of demand charge savings. Thus, by extension, the variation in demand charge savings for each individual rate (at a given PV penetration level) must be driven primarily by differences in the shapes of the customer load profiles.

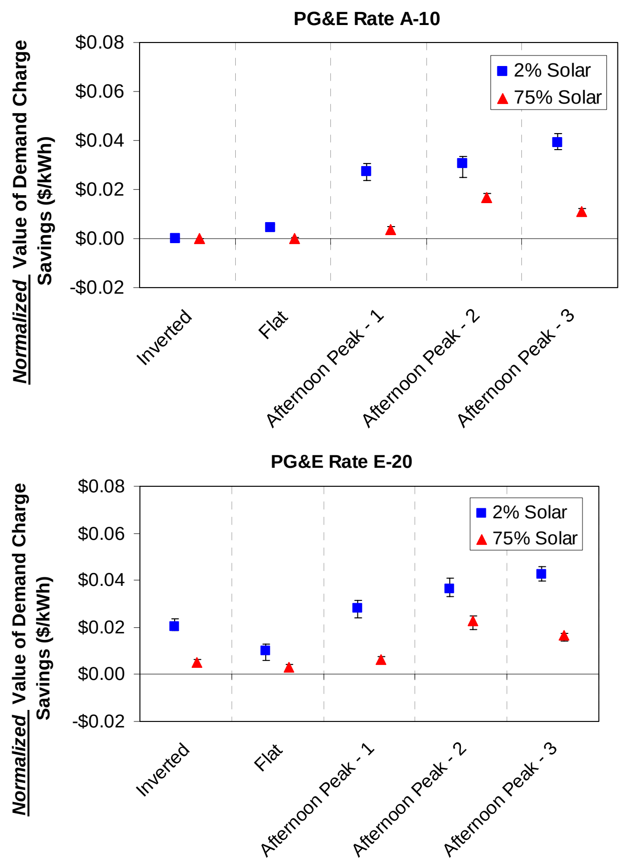

Fig. 6: Variation in Normalized Demand Charge Savings Due to Differences in PV Production Profile

3.4 Impact of Customer Load Shape on the Value of Demand Charge Savings

As we just determined, the specific shape of the customer load profile is the dominant factor driving variation in demand charge savings for any given rate and PV penetration level. In this section, we further examine the impact of customer load shape on demand charge savings, and show how its significance depends, in part, on the specific structure of the demand charges.

In Fig. 7, we compare the normalized value of demand charge savings among the same five representative customers introduced in the previous section (but no mixing-and-matching of PV and load data across sites). For each customer, we show the distribution in normalized demand charge savings across the ten rates with only non-TOD demand charges (top) and across the nine rates with some TOD demand charge (bottom). Thus, in this figure, the percentile bands represent the variation in normalized demand charge savings across the set of rates in each group.

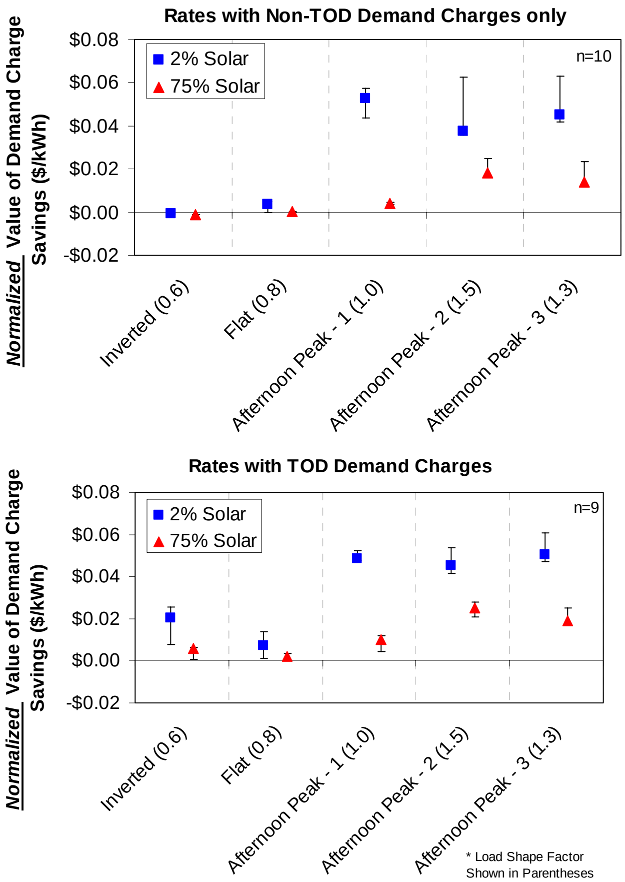

Fig. 7: Variation in Normalized Demand Charge Savings Due to Differences in Customer Load Profile

Based on Fig. 7, we can see that, regardless of the composition of the demand charges, customers with an afternoon peak load shape can receive substantial demand charge savings at low PV penetration levels, and modest but still meaningful savings at high PV penetration levels. In contrast, customers with flat or inverted load profiles earn essentially no demand charge savings on rates without TOD demand charges, as we would expect. On rates with a TOD charge, customers with flat or inverted load profiles may earn some modest amount of demand charge savings, but only at low PV penetration levels.

3.5 Energy Charge Structure

In examining the impact of the energy charge structure on the value of bill savings, we focus on two specific rate design issues: the basic type of energy charge used (flat, seasonal, or TOU) and, for TOU rates, the spread between peak and off-peak prices.

Of the 21 rate schedules in our analysis, 16 have a TOU-based energy charge, four have a seasonal energy charge, and one has a flat energy rate. Fig. 8 compares the distribution in the normalized value of energy charge savings across each group of rates. The percentile bands for each bar reflect both variation among the rates within each group as well as variation in the PV production profiles across the 24 customers.

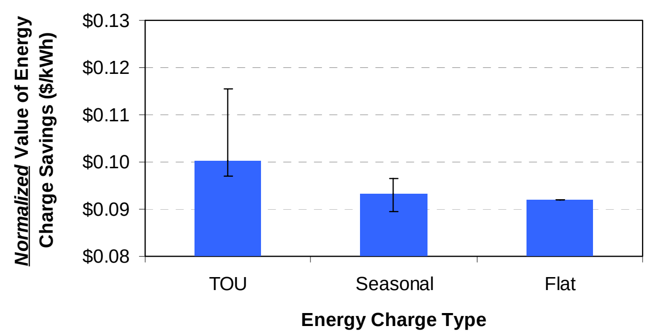

Fig. 8: Normalized Value of Energy Charge Savings According to Energy Charge Structure

As we would expect, the figure shows that the value of energy charge savings is generally greater for TOU-based rates than for those with seasonal or flat energy charges, although perhaps by not as much as might be assumed (less than 10% greater in the median case). The basic reason why energy charge savings are greater for TOU rates is well-understood: TOU rates provide a higher credit for PV production during summer afternoon periods, which is also when production tends to be greatest. Fig. 8 also shows that seasonal energy rates do not necessarily provide greater value than flat rates, and may actually be less valuable in some cases.

Fig. 8 further suggests that, among TOU-based rates, the value of energy charge savings may vary rather substantially depending on the specific TOU design, as indicated by the wide percentile band. One significant distinction among TOU rates, to which we now turn our attention, is the spread between peak and off-peak prices.

To hone in on this particular issue, Fig. 9 plots the distribution of normalized energy charge savings for each TOU rate against the ratio of the summer peak period energy price to the winter off-peak energy price. Because

TOU rates also differ across utilities in terms of the number and definition of TOU periods, Fig. 9 distinguishes among the utilities to visually separate out the influence of these confounding factors.

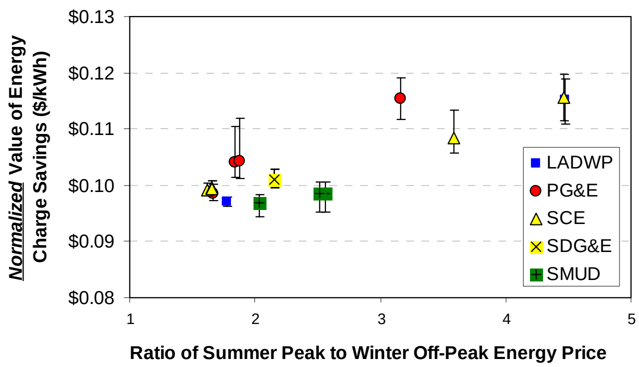

Fig. 9: Normalized Value of Energy Charge Savings According to the Ratio of Summer Peak to Winter Off-Peak Prices

As we would expect, the figure indicates that the value of savings on energy charges increases with greater differentiation between peak and off-peak prices. For TOU rates with the greatest peak to off-peak price ratios, normalized energy charge savings are approximately 15% greater than for those with the least differentiation (a bigger difference than between TOU and non-TOU rates). Another trend evident in Fig. 9 (particularly for SCE) is that the width of the percentile bands, and thus the importance of the PV production profile, increases with the price ratio. We would expect this to occur, given that systems oriented to maximize production during the summer peak period would benefit most from TOU rates with a wide spread between peak and off-peak prices. Conversely, the figure shows that optimizing the orientation of a system to maximize production during summer peak periods offers quite marginal benefit (at least in terms of bill savings), for TOU rates with only modest differentiation between peak and off-peak periods.

4. OPTIMAL RATE SELECTION

The analysis presented thus far assumes that customers are on the same rate before and after PV installation. However, in reality, customers often have a choice of rate options and can select the rate, both before and after PV installation, that minimizes their bill. As we have previously shown, the value of demand charge savings tends to decline with increasing PV penetration. Thus, we would expect that customers with large PV systems relative their building load would generally opt for rates that are more heavily weighted towards energy charges. However, without further analysis, it is unclear how dominant this factor might be among the various other factors that affect the relative cost of alternate rate options.

Of the rate schedules analyzed in this paper, four have minimal or no demand charges: LADWP's A-2, D; PG&E's A-6; SCE's GS-2, TOU Option A; and SCE's TOU GS-3 Option A. Depending on its peak demand, a customer may be able to choose between one of these "PV-friendly" rates and one or more other rate options (see Table 2).

TABLE 2. GROUPS OF RATE OPTIONS

Utility	Customer Size	Rate Options Available
LADWP	30-100 kW	PV-friendly: A-2, D Other rates: A-2, A; A-2, B
PG&E	<200 kW	PV-friendly: A-6 Other rates: A-1, A-10, A-10 TOU, E-19
SCE	20-200 kW	PV-friendly: GS-2 TOU Option A Other rates: GS-2 TOU Option B, GS-2 non-TOU
	200-500 kW	PV-friendly: TOU GS-3 Option A Other rates: TOU GS-3 Option B

In order to better understand the potential significance of "PV-friendly" rates, we determined the optimal rate within each of the four rate groups identified in Table 2, for each of the 24 customers, repeating the analysis across a range of PV penetration levels.

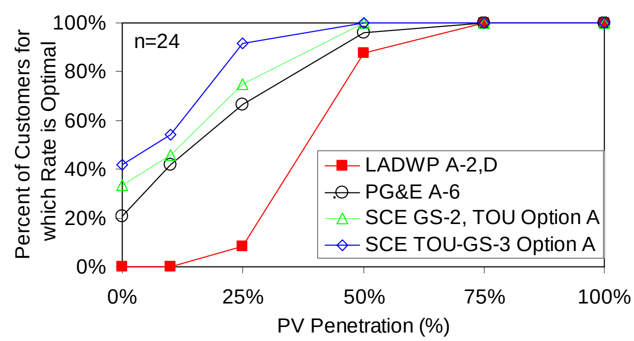

Fig. 10: Customer Choice of Energy-Focused Rates at Varying Levels of PV Penetration

Fig. 10 shows the percentage of customers for which each PV-friendly rate is optimal, compared to the other rate options within the same group. At PV penetration levels greater than 50%, all or nearly all of the customers would minimize their utility bill by switching to the "PV-friendly" rate. However, at low PV penetration levels, these rates would not be optimal for many customers, as customer load characteristics also affect the optimal retail rate. One implication of this finding is that the availability of "PV-friendly" rates is most important for supporting the installation of PV systems that meet a sizeable fraction of the host-customer's load. Another implication is that making PV-friendly mandatory for customers with PV systems may actually dissuade some customers from installing PV. Thus, regulators and utilities that seek to establish rates that support a range of PV applications should consider making those rates optional, rather than mandatory.

5. CONCLUSIONS

We conclude that rate structure details are, indeed, a critical determinant of the economic value received by customers from installing PV. Thus, by extension, choices made by utility regulators in establishing or revising retail rates can have a profound impact on the future viability of solar markets. One important step regulators can take to promote PV systems is to make available, on an *optional* basis, commercial rate schedules with low demand charges and TOU-based energy charges that have a large spread between peak and off-peak prices.

Customers who plan to install PV systems (and retailers selling those systems) should evaluate the full set of rate options available. If the PV system is small relative to the building load (i.e., providing less than 50% of the annual energy consumption), the optimal rate may be one with sizable demand charges. In this case, the customer/retailer should not ignore potential demand charge savings when estimating bill savings, especially for customers whose load shape has an afternoon peak. Given the sensitivity of demand charge savings to the specific customer load shape, estimates of demand charge savings should be done on a customer-specific basis using historical 15-minute interval load data and should be account for the specific type of demand charges for the rate schedules analyzed.

6. ACKNOWLEDGMENTS

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7. REFERENCES

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